BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation pursuant to Senate Bill 380 to determine the feasibility of minimizing or eliminating the use of the Aliso Canyon natural gas storage facility located in the Country of Los Angeles while still maintaining energy and electric reliability for the region.	Investigation 17-02-002 (Filed February 9, 2017)

COMMENTS OF THE UTILITY REFORM NETWORK

ON THE FINAL SCENARIOS FRAMEWORK

Lower bills. Livable planet.

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COMMENTS OF THE UTILITY REFORM NETWORK
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I. INTRODUCTION

Pursuant to the *Administrative Law Judge's Ruling Entering into Record Energy Division's Final Phase 1 Scenarios Framework, Requesting Comment and Setting Procedure to Request Phase 1 Evidentiary Hearings* of September 14, 2018 (Ruling), TURN offers the following comments on the Energy Division's (ED's) *Scenarios Framework* (Framework or Final Proposal), which was included as Attachment A to the Ruling. TURN appreciates the substantial effort Energy Division has spent over the last year developing this Framework and believes it will be useful for evaluating the reliability and cost issues posed by the loss of some or all of the gas storage capabilities of the Aliso Canyon natural gas storage facility.[1] TURN offers limited comments on the Framework below, but may offer additional comments in reply to other parties' comments.

II. Hydraulic Modeling:

TURN has one concern regarding the Framework's proposed method for conducting hydraulic modeling of the Southern California Gas Company (SoCalGas) system. The Framework states it will develop "synthetic" hourly shapes for core gas demands for the "peak (1-in-10) and extreme peak (1-in-35)" gas demand scenarios. To estimate hourly load shapes during peak conditions, the Framework explains that recorded "[l]oad profile shapes will then be scaled up based on the forecasted peak and extreme peak of the simulated future years."[2] TURN interprets this language to mean ED will select an appropriate historic hourly shape and then increase demand

[1] TURN refers to the loss of the various gas storage services that have been provided by the Aliso Canyon natural gas storage facility in these comments using shorthand terms such as "loss of Aliso Canyon".
[2] Framework, p. 12.

in each hour of that load shape by the ratio of the projected maximum hourly demand in a "peak" or "extreme peak" scenario to the historic day's maximum hourly demand.[3] That is, for each hour, core gas demand for an hour in a projected peak day is computed as core gas demand for the same hour in the recorded day multiplied by the ratio of estimated maximum gas demand from the peak scenario divided by the maximum hourly recorded gas demand within that day, as expressed below:

Figure 1

Formula for Scaling Hourly Recorded Gas Demand
to Hourly Gas Demand on Peak Day Implied by Scenario Framework

$$\text{Forecast Gas Demand}_{\text{hour}} = \text{Recorded Gas Demand}_{\text{hour}} \times \left(\text{Forecast Gas Demand}_{\text{max. hrly demand within day}} / \text{Recorded Gas Demand}_{\text{max. hrly demand within day}} \right)$$

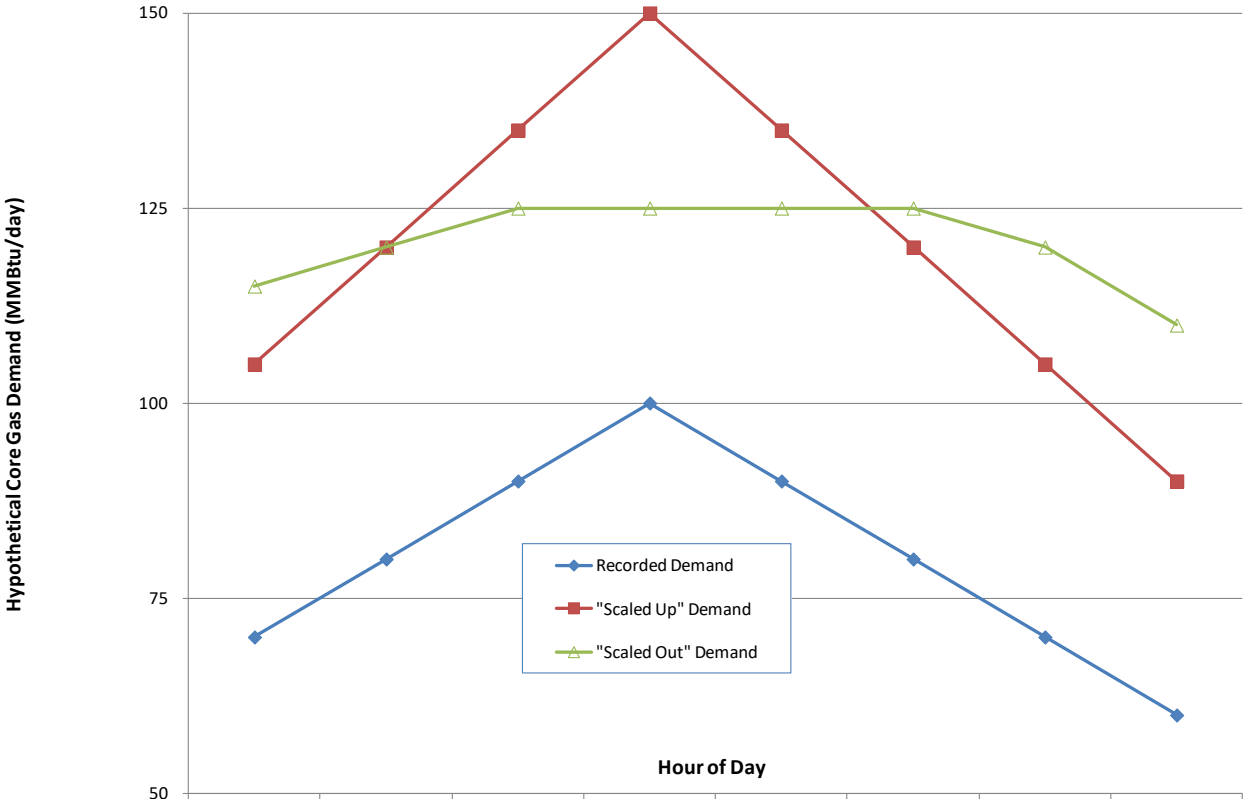
TURN is concerned that simply "scaling up" hourly loads from a non-peak gas demand day to a peak or extreme peak gas demand day may yield a load shape that overestimates the maximum hourly load and underestimates load in hours adjacent to that hour of maximum demand. TURN has this concern because hourly gas demands, however extreme, may approach customers' collective physical ability to burn gas within an hour. In such a case, estimates of hourly core gas demand in the highest hour of a day may be overstated. Further, as such gas demands may be satisfied by burning gas in other hours, hours adjacent to the maximum demand hour may also be misstated.

[3] For simplicity, TURN uses the term "peak" gas demand to refer to both peak and extreme peak demands.

The differences between these two approaches are illustrated in Figure 2 below.

Figure 2

Difference between "Scaling Up" and "Scaling Out" Core Gas Demand to Estimate Hourly Demand on Peak Gas Demand Days



	5	6	7	8	9	10	11	12
Recorded Demand	70	80	90	100	90	80	70	60
"Scaled Up" Demand	105	120	135	150	135	120	105	90
"Scaled Out" Demand	115	120	125	125	125	125	120	110

In Figure 2, the blue line represents a hypothetical load shape for a day's morning hours. The "scaled up" line in red shows the impact of simply multiplying all hours' loads by the same factor – in this case, 1.5 – required to scale up the maximum hourly load in the recorded shape to the estimated maximum load under peak conditions. The "scaled out" line in green shows demand being (a) limited instead to 1.25 times the maximum hourly load in the recorded shape to reflect possible limits on customers' ability to use gas, and (b) being reallocated to hours

surrounding the recorded shape's maximum hourly demand to reflect customers' possible use of gas in such hours.

TURN notes it is critical to estimate hourly gas demands – and thus the estimated "ramping" demands on the SoCalGas system – as accurately as possible. As the Framework notes, "[the most important shape metric is the maximum ramp rate (mathematically termed maximum slope or gradient), which translates to sudden increases in gas demand, and will therefore affect the performance of the pipeline network".[4,5]

TURN thus recommends ED use some degree of "scaling out" to develop hourly core gas demand load shapes for peak and extreme peak days, rather than simply "scaling up" all of a recorded shape's hourly loads by the same factor. TURN recommends ED evaluate the most extreme available peak day to determine whether the "peak hour" should be scaled by some fraction (potentially between 0.70 and 0.90) of the actual ratio calculated in the formula shown in Figure 1.

III. Production Cost Modeling

A. Modeling Gas Delivery Constraints

In the Framework, Energy Division proposes, as it has in the prior draft scenario framework, to assess the impact of gas delivery constraints on gas generators in the Western Los Angeles Basin by restricting local gas resources' operating capabilities in the production cost model.[6] TURN

[4] *Id*., p. 12.
[5] TURN does not know if some degree of "scaling out" to develop hourly core gas demands will raise or lower gas ramping needs; such "scaling out" may minimize the ramping required to meet peak hour core gas loads, but might increase the ramping demands in other hours of the day.
[6] Framework, p. 30.

has expressed concern about this approach before and appreciates the Framework's recognition of these concerns. Specifically, the Framework states that ED:

> "will also seek to simulate the effect of a Rule 23 curtailment on a 1-in-35 (extreme peak) design day by limiting total gas volume to all the power plants in the SoCalGas system and simulating the effect of a total volumetric constraint over a group of power plants."[7]

The Framework suggests Energy Division will also consider other modeling techniques to mimic the impacts lower gas flows and pressures may have on generators.[8] TURN recognizes that modeling such impacts may not be straightforward in production cost models and appreciates ED's interest in pursuing reasonable approaches to this modeling challenge.

B. Electricity and Heating

The Framework states that "under the 1-in-35 (extreme peak) design standard adopted in SoCalGas Tariff Rule 23, complete curtailment of a larger group of electric generators may be required to protect core customer gas supply."[9] TURN does not dispute the statement *per se*, but notes that to heat their homes and businesses, core customers will also need electric service to operate their gas heaters' circulation fans. That is, without electric service, gas service is of no use for most home heating systems. TURN recognizes that the Framework is not suggesting interrupting electric service – just curtailing a group of gas-fired electric generators – but Energy Division should recognize the necessity of maintaining some level of electric service as a necessity to maintaining customers' gas heating capabilities.[10]

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[7] *Id*.
[8] *Id*., p. 57.
[9] *Id*., p. 27.
[10] TURN recognizes that it may not be practical, or even possible, to address such considerations in production cost modeling. Rather, TURN raises this issue for the Commission's and parties' consideration when assessing modeling results and policy decisions.

C. Senate Bill 100

The Ruling asked how the increase in the Renewable Portfolio Standard target from 50 percent to 60 percent by 2030 that was implemented by recently-enacted Senate Bill (SB) 100 "can be accommodated in the proposed modeling."[11] TURN believes the data used for Production Cost Modeling in this docket (and all similar analyses in other Commission dockets) should reflect this increased RPS target for 2030 as soon as reasonably possible. TURN recognizes, however, that this possibility might not be immediately achievable, given the need to determine specifically what types of resources will be assumed to comprise the additional renewables needed to reach the 60 percent RPS target.[12]

Increased amounts of renewable generation will reduce *total* gas demand in California, including the SoCalGas system. However, higher amounts of renewables may *increase* the need for *electric* ramping products, particularly if such additional renewables are comprised mostly of solar photovoltaic resources. Such increases in electric ramping needs might lead to increased demand for gas ramping services as well, depending on the alternatives used to meet electric ramping needs, and may thus increase hourly gas demands during certain hours and days.

TURN also notes that the Commission-adopted Reference System Plan (RSP) – which is meant to guide development of the state's electric resources – anticipates that 58 percent of 2030 loads will be met by renewables; this outcome was driven by the Commission's imposition of the goal

[11] Ruling, p. 3.
[12] For example, procurement of additional solar resources will likely have a different impact on electric ramping needs than would procurement of additional renewables with a "baseload" production profile.

of reducing Greenhouse Gas (GHG) emissions by 2030, which resulted in renewable generation in 2030 exceeding the 50 percent RPS target.[13]

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Respectfully submitted,

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[13] See Decision (D.) 18-02-018, pp. 79-91 for Commission's discussion of the RSP in general. A figure of "very close to 60 percent" was cited at p. 13 of the *Joint Ruling of Assigned Commissioner and Administrative Law Judge…* issued October 5 in R.16-02-007. The specific figure of 58 percent is shown on slide 58 of ED's presentation of the RSP available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M195/K910/195910807.PDF. TURN notes that four percent of such RPS-eligible resources use would be the IOUs crediting their "banked" quantities of past excess renewable procurement against 2030 requirements.